Electricity

Electricity consumption nearly doubles in the IEO2003 projections. Developing nations in Asia and in Central and South America are expected to lead the increase in world electricity use.

In the *International Energy Outlook 2003* (*IEO2003*) reference case, worldwide electricity consumption is projected to increase at an average annual rate of 2.4 percent from 2001 to 2025 (Table 22 and Figure 77). The most rapid projected growth in electricity use by region is 3.7 percent per year for developing Asia, where robust economic growth is expected to increase demand for electricity to run newly purchased home appliances for air conditioning, refrigeration, cooking, and space and water heating. By 2025, developing Asia as a whole is expected to consume almost 2.5 times as much electricity as it did in 2001. In China, electricity consumption is projected to grow by an average of 4.3 percent per year, nearly tripling over the forecast period.

In Central and South America, as in developing Asia, high rates of economic growth are expected to improve standards of living and increase electricity use for industrial processes and in homes and businesses. The expected growth rate for electricity use in Central and South America is 3.3 percent per year. In Brazil, the region's largest economy and largest consumer of electricity, electricity consumption is projected to increase by 3.2 percent per year, with electrification coming to rural populations that previously have not had access to the national grid.

Electricity consumption in the industrialized world is expected to grow at a more modest pace than in the developing world, at 1.7 percent per year. In addition to expected slower growth in population and economic activity in the industrialized nations, market saturation and efficiency gains for some electronic appliances are expected to slow the growth of electricity consumption from historical rates.

Primary Fuel Use for Electricity Generation

The mix of primary fuels used to generate electricity has changed a great deal over the past three decades on a worldwide basis. Coal has remained the dominant fuel, although electricity generation from nuclear power increased rapidly from the 1970s through the mid-1980s, and natural-gas-fired generation has grown rapidly in the 1980s and 1990s. In contrast, in conjunction with the high world oil prices brought on by the oil price shocks resulting from the OPEC oil embargo of 1973-1974 and

Table 22. World Net Electricity Consumption by Region, 1990-2025
(Billion Kilowatthours)

Region	History		Projections					
	1990	2001	2005	2010	2015	2020	2025	Average Annual Percent Change, 2001-20205
Industrialized Countries	**6,368**	**8,016**	**8,307**	**9,200**	**10,106**	**11,030**	**11,994**	**1.7**
United States	2,827	3,602	3,684	4,101	4,481	4,850	5,252	1.6
EE/FSU	**1,906**	**1,528**	**1,768**	**1,982**	**2,204**	**2,423**	**2,642**	**2.3**
Developing Countries	**2,272**	**4,390**	**4,886**	**5,962**	**7,172**	**8,555**	**10,038**	**3.5**
Developing Asia	1,259	2,730	3,103	3,851	4,697	5,634	6,604	3.7
China	551	1,312	1,545	1,966	2,428	2,986	3,596	4.3
India	257	497	528	662	802	958	1,104	3.4
South Korea	93	270	296	372	443	498	552	3.0
Other Developing Asia	358	650	734	850	1,024	1,192	1,352	3.1
Central and South America	463	721	782	925	1,081	1,302	1,577	3.3
Total World	**10,546**	**13,934**	**14,960**	**17,144**	**19,482**	**22,009**	**24,673**	**2.4**

Note: EE/FSU = Eastern Europe and the former Soviet Union.

Sources: **History:** Energy Information Administration (EIA), *International Energy Annual 2001*, DOE/EIA-0219(2001) (Washington, DC, February 2003), web site www.eia.doe.gov/iea/. **Projections:** EIA, System for the Analysis of Global Energy Markets (2003).

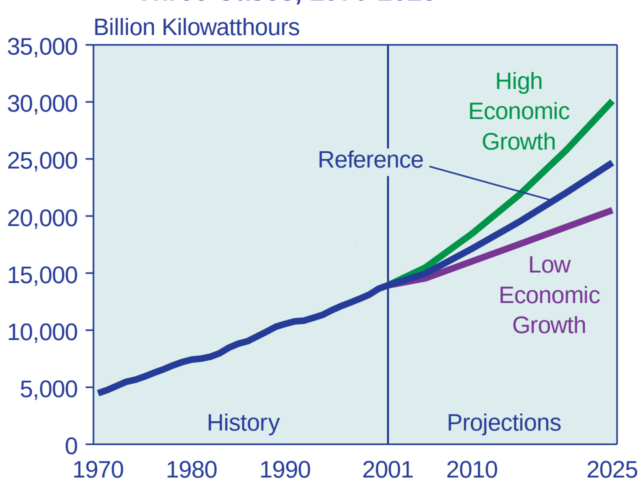
the Iranian Revolution of 1979, the use of oil for electricity generation has been slowing since the mid-1970s.

In the *IEO2003* reference case, continued increases in the use of natural gas for electricity generation are expected worldwide. Coal is projected to continue to retain the largest market share of electricity generation, but its importance is expected to be diminished somewhat by the rise in natural gas use. The role of nuclear power in the world's electricity markets is projected to lessen as reactors in industrialized nations reach the end of their lifespans and few new reactors are expected to replace them. Generation from hydropower and other renewable energy sources is projected to grow by 56 percent over the next 24 years, but their share of total electricity generation is projected to remain near the current level of 21 percent.

Natural Gas

Electricity markets of the future are expected to depend increasingly on natural-gas-fired generation. Industrialized nations are intent upon using combined-cycle gas turbines, which usually are cheaper to construct and more efficient to operate than other fossil-fuel-fired generation. Natural gas is also seen as a much cleaner fuel than other fossil fuels. Worldwide, natural gas use for electricity generation is projected to be almost 2.5 times greater in 2025 than it was in 2001 (Table 23), as technologies for natural-gas-fired generation continue to improve and ample gas reserves are exploited. In the developing world, natural gas is expected to be used to diversify electricity fuel sources, particularly in Central and South America, where heavy reliance on hydroelectric power has led to shortages and blackouts during periods of severe drought.

Figure 77. World Net Electricity Consumption in Three Cases, 1970-2025



Sources: **History:** Energy Information Administration (EIA), *International Energy Annual 2001*, DOE/EIA-0219(2001) (Washington, DC, February 2003), web site www.eia.doe.gov/iea/. **Projections:** EIA, System for the Analysis of Global Energy Markets (2003).

The former Soviet Union (FSU) accounted for more than one-third of natural gas usage for electricity generation worldwide in 2001, and natural gas provided 42 percent of the energy used for electricity generation in the FSU. By 2025, natural gas is projected to account for 63 percent of the electricity generation market in the FSU. Relying increasingly on imports from Russia, the nations of Eastern Europe are also expected to increase their use of natural gas for electricity generation, from a 9-percent share of total generation in 2001 to 50 percent in 2025.

In North America, the natural gas share of the electricity fuel market in the United States is projected to increase from 18 percent in 2001 to 24 percent in 2025, with Canadian exports expected to provide a growing supply of natural gas to U.S. generators. The natural gas share of electricity generation in Canada is also projected to grow, from 3 percent in 2001 to 11 percent in 2025.

Natural gas consumption for electricity generation in Western Europe is projected to nearly triple over the forecast period, and its share of the region's electricity fuel market is projected to grow from 17 percent in 2001 to 38 percent in 2025 as the nuclear power and coal shares are reduced. After the oil crisis of 1973, European nations actively discouraged the use of natural gas for electricity generation (as did the United States) and instead favored domestic coal and nuclear power over dependence on natural gas imports. In 1975 a European Union (EU) directive restricted the use of natural gas in new power plants. The natural gas share of the electricity market in Western Europe fell from 9 percent in 1977 to 5 percent in 1981, where it remained for most of the 1980s. In the early 1990s, the growing availability of reserves from the North Sea and increased imports from Russia and North Africa lessened concerns about gas supply in the region, and the EU directive was repealed.

In Central and South America natural gas accounted for 9 percent of the electricity fuel market in 2001. Its share is projected to grow to 46 percent in 2025. Hydropower is the major source of electricity supply in South America at present, but environmental concerns, cost overruns on large hydropower projects in the past, and electricity shortfalls during periods of drought have prompted South American governments to view natural gas as a means of diversifying their electricity supplies. A continent-wide natural gas pipeline system is being built in South America, which will transport Argentine and Bolivian gas to Chile and Brazil.

Per capita consumption of natural gas in Asia and Africa is relatively small when compared with Europe and North America. In 2001, Japan accounted for one-fourth of natural gas consumption in Asia. Almost all natural gas consumed in Japan is imported as liquefied natural gas (LNG). Japan is expected to maintain its dependence on natural gas at around 20 percent of the electricity fuel market through 2025.

Coal

In 2025, coal is expected to account for 31 percent of the world's electricity fuel market, slightly lower than its 34-percent share in 2001. The United States accounted for 40 percent of all coal use for electricity generation in 2001, and China and India together accounted for 27 percent. In the *IEO2003* forecast, the coal share of U.S. electricity generation is expected to remain at roughly 50 percent through 2025. China's coal share is projected to rise slightly, to 73 percent in 2025 from 72 percent in 2001. Over the same period, coal's share of India's electricity market is expected to decline from 72 percent to 63 percent. Although coal remains a relatively cheap source of electricity production, natural gas is viewed as being environmentally superior, and the economics of natural gas generation technology are improving, particularly in countries with access to gas pipelines.

Reliance on coal for electricity generation is also expected to be reduced in other regions. In Western Europe, for example, coal accounted for 20 percent of the electricity fuel market in 2001 but is projected to have only a 12-percent share in 2025. Similarly, in Eastern Europe and the FSU (EE/FSU), coal's 27-percent share of the electricity fuel market in 2001 is projected to fall to 6 percent in 2025. For years, massive state subsidies were all that kept many coal mines operating in Western and Eastern Europe. In many cases, the subsidies were underwritten by electricity consumers. The EU has adopted policy measures to eliminate or reduce state subsidies for domestic coal production, and only four EU member states (the United Kingdom, Germany, Spain, and France) continue to produce hard coal.

Nuclear Power

The nuclear share of energy use for electricity production is expected to decline in most regions of the world as a result of public opposition, waste disposal issues,

Table 23. World Energy Consumption for Electricity Generation by Region and Fuel, 2000-2025
(Quadrillion Btu)

Region and Fuel	History		Projections				
	2000	2001	2005	2010	2015	2020	2025
Industrialized	**89.0**	**89.6**	**92.1**	**99.9**	**106.4**	**113.3**	**120.1**
Oil	5.0	4.9	4.5	4.6	5.0	5.2	5.5
Natural Gas	14.3	14.7	16.6	19.4	23.5	28.4	33.5
Coal	30.5	30.9	32.3	34.8	35.4	36.1	37.7
Nuclear	22.6	22.4	21.6	22.3	22.4	21.9	20.4
Renewables	16.5	16.7	17.2	18.9	20.0	21.7	23.0
EE/FSU	**23.2**	**22.6**	**20.6**	**22.8**	**25.3**	**26.3**	**27.0**
Oil	1.5	1.3	0.4	0.5	0.9	1.2	0.8
Natural Gas	7.9	8.0	8.5	9.5	12.0	13.7	16.1
Coal	6.3	6.0	4.9	4.1	3.6	2.7	1.6
Nuclear	4.3	4.1	3.2	3.3	3.3	3.0	2.6
Renewables	3.2	3.2	3.6	5.5	5.6	5.7	5.8
Developing	**39.8**	**41.2**	**47.0**	**55.0**	**64.1**	**74.1**	**85.0**
Oil	5.0	5.3	6.2	6.0	6.8	7.6	8.2
Natural Gas	6.3	6.5	7.2	9.8	13.4	16.7	21.0
Coal	14.4	15.1	18.1	21.4	23.8	28.3	32.7
Nuclear	2.6	2.7	2.7	3.1	4.2	4.5	5.0
Renewables	11.4	11.7	12.8	14.6	15.9	17.0	18.0
Total World	**151.9**	**153.4**	**159.7**	**177.7**	**195.7**	**213.7**	**232.0**
Oil	11.6	11.5	11.1	11.1	12.7	14.0	14.5
Natural Gas	28.4	29.2	32.3	38.7	48.8	58.9	70.6
Coal	51.2	52.0	55.2	60.3	62.9	67.1	72.0
Nuclear	29.5	29.1	27.5	28.7	29.8	29.4	28.0
Renewables	31.1	31.6	33.5	38.9	41.5	44.4	46.9

Note: EE/FSU = Eastern Europe and the former Soviet Union.

Sources: **History:** Derived from International energy Agency, *Energy Statistics of OECD Countries 1999-2000* (Paris, France, 2002), and *Energy Statistics of Non-OECD Countries* (Paris, France, 2002). **Projections:** EIA, System for the Analysis of Global Energy Markets (2003).

concerns about nuclear arms proliferation, and the economics of nuclear power. The nuclear share of electricity generation worldwide is projected to drop to 12 percent in 2025 from 19 percent in 2001.

In the United States, the nuclear share is projected to decline from 19 percent of the electricity fuel market in 2001 (second behind coal) to 15 percent in 2025. In Canada, where the nuclear share of the market has been declining since 1984, its 22-percent share in 2001 is projected to fall to 11 percent in 2025. In Western Europe, where Finland is the only country projected to build new nuclear units, the nuclear share of the region's electricity fuel market is projected to fall from 34 percent in 2001—more than any other energy source—to 21 percent in 2025.

In Japan, nuclear power accounted for 39 percent of the energy used for electricity generation in 2001. That share is expected to decline to 31 percent by 2025 in the *IEO2003* forecast. In the EE/FSU region, the nuclear share is projected to decline from 18 percent in 2001 to 10 percent in 2025.

Nuclear power contributes very little to electricity generation in the developing nations of Central and South America, Africa, and the Middle East, and it is expected to contribute little in 2025. In Central and South America, only Argentina and Brazil were nuclear power producers in 2001. In Africa, only South Africa generated electricity from nuclear power in 2001. There are no nuclear power plants in operation in the Middle East, although two are under construction in Iran.

In contrast to the rest of the world's regions, in developing Asia nuclear power is expected to play a growing role in electricity generation. China, India, Pakistan, South Korea, and Taiwan currently have nuclear power programs, and the nuclear share of the region's electricity fuel market is expected to remain stable at roughly 9 percent from 2001 through 2025. China is expected to account for most of the region's nuclear power capacity additions.

Hydroelectricity and Other Renewables

Renewable energy, predominantly hydropower, accounted for one-fifth of the world's energy use for electricity generation in 2001, where it is expected to remain through 2025. Of the world's consumption of renewable energy for electricity production in 2001, the United States and Canada together accounted for almost 29 percent of the total, Western Europe for 20 percent, and Central and South America 19 percent (despite consuming just 5 percent of the world's electricity).

In 2001, renewables accounted for 9 percent of electricity production in the United States and 56 percent in Canada, both nations where hydroelectric power has been extensively developed. Their shares are expected to grow slightly by 2025. In North America and throughout the world, generation technologies using nonhydroelectric renewables are expected to improve over the forecast period, but they still are expected to be relatively expensive in the low price environment assumed for energy fuels in the *IEO2003* reference case.

Hydroelectricity is used the most for electricity generation in Central and South America, and renewables accounted for 73 percent of the region's electricity fuel market in 2001. Recent experiences with drought, cost overruns, and the negative environmental impacts of several large-scale hydroelectric projects have reduced the appeal of hydropower in South America, however, and the renewable share of electricity generation in the region is expected to decline to 45 percent by 2025 as countries work to diversify their electricity fuel mix.

Most of Western Europe's renewable energy consumption consists of hydroelectricity. Renewables in total accounted for 24 percent of the region's electricity market in 2001, and their share is expected to increase to 25 percent in 2025. Some European nations, particularly Denmark and Germany, are actively developing their nonhydroelectric renewable energy resources, most notably wind.

Some near-term growth in renewable energy use is expected in developing Asia, particularly in China, where the 18,200-megawatt Three Gorges Dam and a number of other major hydropower projects are expected to become operational during the forecast period. Developing Asia relied on renewables for 18 percent of its electricity production in 2001, and that share is expected to shrink slightly, to 16 percent in 2025.

Oil

The role of oil in the world's electricity generation market has been on the decline since the 1979 oil price shock. Oil accounted for 23 percent of electricity fuel use in 1977; in 2001 its share stood at 7 percent. Energy security concerns, as well as environmental considerations, have already led most nations to reduce their use of oil for electricity generation. In regions where oil continues to hold a significant share of the generation fuel market, such as the FSU and the Middle East, it generally is expected to maintain its position. As a result, the oil share of world energy use for electricity production is projected to remain stable at between 6 and 7 percent through 2025.

Developing Asia accounted for 18 percent of the world's consumption of oil for electricity generation in 2001, when 7 percent of its electricity fuel use consisted of oil (down from 29 percent in 1977). The oil share of electricity fuel consumption in developing Asia is expected to remain stable through 2025. In the petroleum-rich

Middle East, oil supplied 38 percent of the energy used for electricity generation in 2001, and its share is projected to decline slightly, to 34 percent in 2025.

Foreign Investment in Electricity

In the mid- to late 1990s, a massive amount of U.S. capital crossed oceans to acquire electricity assets. Those mergers and acquisitions gave rise to the multinational electricity company. U.S. capital investment targeted nations and regions that were engaged in electricity reforms, which often included privatization and removal of restrictions on foreign investment. Major targets included South America, Australia, and the United Kingdom. Large amounts of non-U.S. foreign capital also flowed into those electricity markets, particularly from Europe.

Over the past few years, the flow of foreign capital into South American electricity ventures has stalled. The same is true of the outflow of U.S. capital into Western Europe and Australia. The slowdown was in part caused by the sluggish state of the global economy and a reduction in international capital flows[24] in general [***1***], as well as the disappointing financial performance of many earlier electricity acquisitions. U.S. companies in particular have retreated from several markets which they quickly grew to dominate in the late 1990s, such as Australia and the United Kingdom, in many instances citing disappointing financial results as a cause for the departure.

Domestically, the United States saw a major wave of mergers and acquisitions in electricity through much of the 1990s, giving rise to electricity producers with a national presence. Some mergers and acquisitions also involved more vertical integration among energy companies. Several involved both natural gas and electricity producers, leading to a greater convergence between electricity fuel producers and electricity generators. U.S. mergers and acquisitions peaked in 1999, however, and have since slowed to a trickle. During the 1990s many mergers and acquisitions were financed through equity swaps. The weakness in equity markets for roughly the past 2 years may have forestalled further consolidation of the U.S. electricity industry.

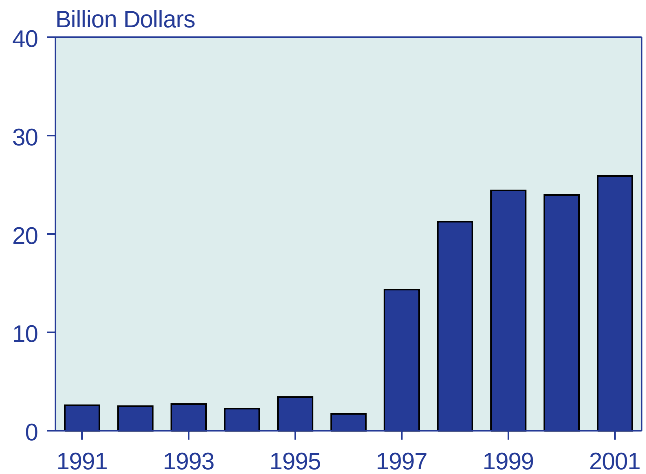
Many developing countries, particularly in Asia and South America, opened their electricity sectors to private capital, much of which came from overseas investors, in the 1990s. Growing foreign investment provided an important source of capital for the construction of new generating capacity to meet rapidly growing electricity demand. Those investments peaked in 1997, and by 2001 they were only about one-fifth of their 1997 levels.

In contrast, continental Europe has only recently seen a wave of merger and investment activity, both internally and across borders. In 1996, the then 15 members of the EU adopted an electricity directive, which became effective in 1997 [***2***]. The goal of the directive was to establish a single European electricity market. Recent merger and acquisition activities on the continent suggest that the market is moving in that direction as far as ownership goes.

United States

Financial flows from the United States into electricity assets overseas leveled between 1999 and 2001 (Figure 78). Among developed countries, a large share of the flow of U.S. overseas investment during the mid-1990s was to the United Kingdom, shortly after the country's 12 distribution companies were privatized and its electricity market was opened to foreign investment (Table 24). The first U.S. acquisition in the UK electricity sector was in 1995, when Southern Company and PP&L Resources purchased the distribution company SWEB (formerly South Western Electricity). Of the 12 UK distribution companies, 8 were purchased by U.S.-based

Figure 78. U.S. Direct Investment in Overseas Utilities, 1991-2001



Note: The utility investments shown include, in addition to electricity, natural gas distribution and sanitary services; however, the sharp rise in investments from 1996 to 1999 is largely the result of investments in overseas electric utilities by U.S. companies.

Source: U.S. Department of Commerce, Bureau of Economic Analysis, *Survey of Current Business* (Washington, DC, various issues).

[24]For foreign investment this chapter looks at the absolute stock of investment in overseas utilities. This stock represents the net effect of both outflows and inflows. The foreign direct investment (FDI) position is the cumulative net flow of funds between a foreign-affiliated company and its foreign owners. The U.S. Department of Commerce, the agency that collects data on FDI, measures FDI as the book value of foreign direct investors' equity in, and net outstanding loans to, their U.S. affiliates. The Commerce Department defines a U.S. affiliate as a U.S. business enterprise in which one foreign direct investor owns 10 percent or more of the voting securities or the equivalent.

utilities. Since the mid-1990s, however, French and German utilities have supplanted U.S. companies in the UK market. U.S. utilities have sold 5 of their UK distribution companies since 1998.

Figure 79 shows U.S. investment flows into the utility sectors of Australia, Brazil, and the United Kingdom.[25] In recent years U.S. investment in UK and Australian electricity concerns has waned. The U.S. foreign direct

Table 24. Mergers and Acquisitions in UK Electricity

Company	Current Owners	Date of Acquisition
Regional Distribution and Supply Companies		
UK Companies Purchased by Foreigners		
Eastern Group	Texas Utilities	1998
Midlands Electricity	Avon Energy Partners	1996
Northern Electric and Gas	CalEnergy	1996
SEEBOARD	Central and South West Corporation	1996
SWEB	Southern Company & PP&L Resources	1995
Yorkshire Electricity	American Electric Power and New Century Energies	1997
London Electricity	Entergy	1996
Yorkshire Electricity	American Electric Power & PS Colorado	1996
UK Companies Sold to UK Owners		
East Midlands Electricity	PowerGen	1998
Manweb	Scottish Power	1995
Norweb	North West Water	1995
Southern Electric	Scottish Hydro-Electric (merger)	1998
SWALEC	Welsh Water	1996
SWALEC (Supply)	British Energy	1999
Yorkshire Electricity	Innogy (UK)	2001
Yorkshire Electricity	Northern Electric	2001
Midlands Electricity (Supply)	National Power	1998
UK Companies Sold to European Owners		
London Electricity	Electricité de France	1998
SWEB (Supply)	London Electricity	1999
Northern Electric	Berkshire Hathaway (U.S.) and RWE (German)	1999
Norweb	E.ON (German)	2002
SEEBOARD	Electricité de France	2002
Generation and Transmission Companies		
UK Companies Purchased by Foreigners		
PowerGen	E.ON	2001
Eastern Electricity	Electricité de France	2002
SWEB[a]	Electricité de France	1999
U.S. Companies Purchased by or Merged with UK Companies		
LG&E	PowerGen	2000
Various generation assets	International Power	—[b]
New England Electric System	National Grid Company	1999
Pacificorp	Scottish Energy	1999
AmerGen[c]	British Energy	1999

[a]Electricité de France purchased SWEB's customer supply business.
[b]International Power had 4,000 megawatts of capacity in operation in the United States in late 2002. Source: International Power Corporation, web site www.ipplc.com.
[c]AmerGen is a joint venture between British Energy and its U.S. partner Exelon.
Source: UK Electricity Association, News Releases (1998-2003), web site www.electricity.org.uk.

[25]Most of the investment shown was in electric utilities; however, the data source did not separate electric utilities from other utilities, such as natural gas and sanitary.

investment position in South American utilities may also have peaked, although the data have yet to indicate it.

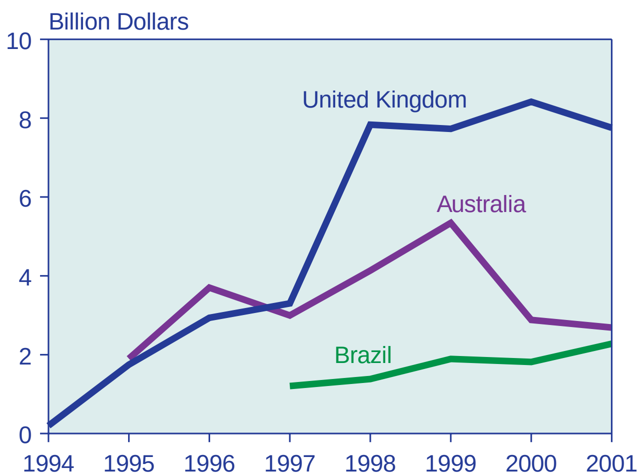
In many cases, U.S. companies paid a premium for their overseas utility acquisitions and may not have been able to realize expected returns. In the United Kingdom, for example, unexpected regulatory interventions led to a considerable drop in earnings for U.S. companies invested in UK electricity distribution companies [***3***]. In South America, economic recession and currency fluctuations made repayment of interest and principal on loans used to acquire electricity assets exceedingly difficult. Further, some South American countries have been reluctant to allow utilities to raise prices in order to recoup increased fuel costs and capital and interest costs [***4***]. A new political horizon appears to be emerging in much of South America with the election of several new governments in recent years. As a result, in the near term, little if any new foreign investment capital is expected to flow into South American electricity ventures.

Total investment in U.S. utilities by foreign companies also increased dramatically during the late 1990s (Figure 80). Although trailing the wave of U.S. investment in electricity overseas by about 2 years, foreign companies had invested roughly as much in U.S. utilities by 2000 as U.S.-based companies had invested overseas. By far the largest share of foreign investment in U.S. utilities has come from the United Kingdom. The largest foreign-owned acquisition of a U.S. utility thus far has been Scottish Power's purchase of PacifiCorp of Oregon for $12.9 billion. Other important transactions include the purchase of LG&E by the United Kingdom's PowerGen for $5.4 billion in 2000; the purchase of New England Electric System by UK's National Grid Company's for $3.2 billion in 2000; and British Energy's joint venture with U.S.-based Exelon to form AmerGen.

In the mid- to late 1990s, there was also a wave of domestic mergers and acquisitions in the U.S. electricity sector (Figure 81). By 2000 the trend had started to slow. Only five announcements were made in 2001, and by mid--year 2002 only one announcement had been made. Measured by announcement, domestic mergers and acquisitions among U.S. electricity companies reached a peak of 26 in 1999.

Several factors drove the U.S. electricity industry retrenchment: falling stock prices and the difficulties that posed in capital formation [***5***, ***6***]; a slowdown in domestic economic growth; the fallout the entire industry experienced as a result of the financial scandal surrounding Enron and other energy companies; and the recent spate of overbuilds during the late 1990s and early 2000s. The collapse of the U.S. electricity merger and acquisition market can be traced in part to the poor financial performance of the industry since 1999. Overexpansion in the late 1990s and early 2000s may have been one cause for the lack of activity as the U.S.

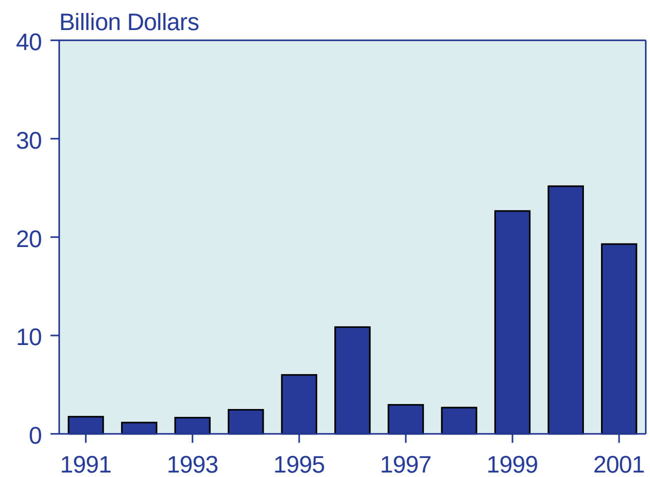
Figure 79. U.S. Direct Investment in Australian, Brazilian, and United Kingdom Utilities, 1994-2001



Notes: The utility investments shown include, in addition to electricity, natural gas distribution and sanitary services; however, the sharp rise in investments in 1994 and 1999 is largely the result of investments in overseas electric utilities by U.S. companies. For some years, data were not made available for U.S. investments in Brazil and Australia due to the Commerce Department's disclosure rules regarding individual companies.

Source: U.S. Department of Commerce, Bureau of Economic Analysis, *Survey of Current Business* (Washington, DC, various issues).

Figure 80. Foreign Direct Investment in U.S. Utilities, 1991-2001



Note: The utility investments shown include, in addition to electricity, natural gas distribution and sanitary services; however, the sharp rise in investments during the late 1990s is largely the result of investments in U.S. electric utilities by foreign companies.

Source: U.S. Department of Commerce, Bureau of Economic Analysis, *Survey of Current Business* (Washington, DC, various issues).

economy fell into recession just as a number of new capacity builds came on line. Between 2000 and 2002, 133,457 megawatts of capacity were added to the U.S. electrical grid, four times the amount of capacity brought on during the previous 5 years [*7*]. In the process of this expansion, electricity companies amassed unusually high debt loads, making further expansion in the face of weakened economic growth doubtful. Between 1998 and 2001, the fixed-income debt of electric utilities more than doubled [*8*].

Hurt worst by falling stock prices were those companies that diversified most from their core utility businesses. Some companies have exited the nascent business of electricity trading, and others have sold off assets acquired domestically and overseas [*9*]. Several companies have seen their share prices plummet and their debt downgraded to junk status [*10*]. According to a Standard and Poor report, during the first 9 months of 2002, 135 debt downgrades of electric utility holding companies took place, roughly four times the number during the same period a year earlier [*11*]. The report also noted that 11 percent of the companies surveyed were rated below investment grade.

In the late 1990s and early 2000s, much of the construction or acquisition of electricity generation assets was financed by short-term debt, which has exposed several companies to severe financial difficulties in 2003. It has been estimated that utilities would need to refinance $50 billion in debt in early 2003. Utility financial health may continue to deteriorate over the next several years if the gap between available margins and utilized margins widens. Fears of future overcapacity have led to the cancellation of several power plants planned for completion during 2003 and 2004 [*12*]. The Energy Information Administration forecasts growth in reserve margins from 16 percent in 2001 to 18 percent in 2004 [*13*].

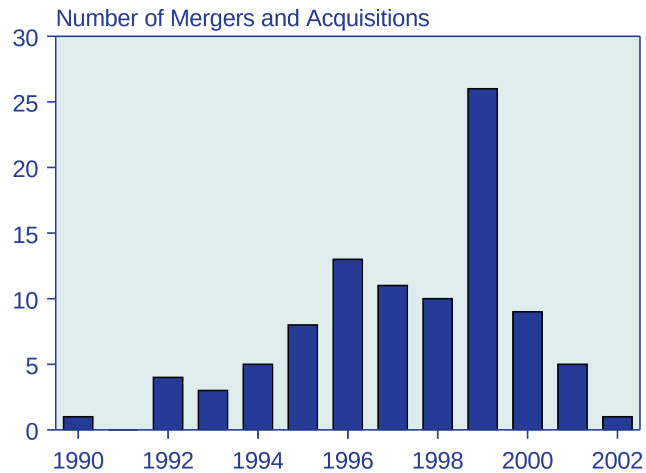
Developing Countries

Developing nations are projected to consume 5,648 billion more megawatthours of commercial electricity in 2025 than in 2001 (see Table 22). An important element in that consumption growth will be investment spending needed for the developing world's electricity generation capacity to keep pace with future demand. Many developing nations have ambitious goals to expand their electricity infrastructure over the coming decades. Some plans may prove feasible and others not. A major concern over whether developing countries can meet their goals is how readily capital will become available to fund needed investments.

Foreign investment in electricity, both private and noncommercial, has played a growing role in many nations' electricity sectors over the past decade (Figure 82 and Table 25). In developing countries, after peaking at $49 billion in 1997, private investment in electricity projects dropped to $10 billion in 2001, roughly equal to the level in 1992, when foreign investment in electricity in developing nations first took off.

By region, however, private capital investment differs in several ways. In some countries, foreign investment has been restricted to new capacity additions, or primarily to new electric power generation. This has generally been true of Asia. In other countries, foreign investment has been free to acquiring existing assets, e.g., a state-owned

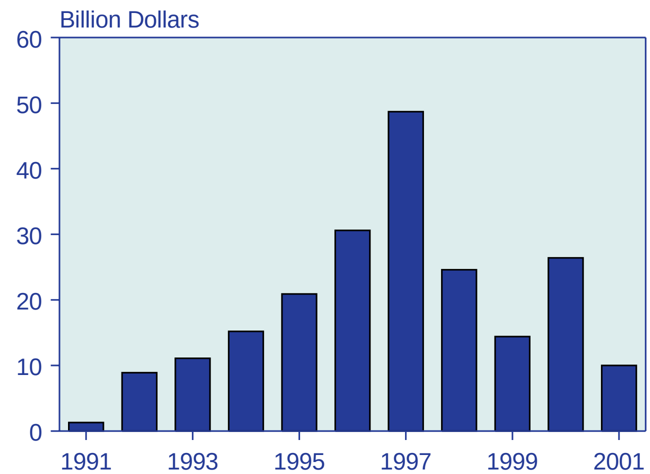
Figure 81. Mergers and Acquisitions in the U.S. Electricity Industry, 1990-2002



Note: Data for 2002 cover the period from January through July.

Source: Edison Electric Institute, "Mergers and Acquisitions" (December 31, 2002), web site www.eei.org/issues/finan/fininfo/021231ma.xls.

Figure 82. Private Sector Investment in Electricity Projects in Developing Countries, 1991-2001



Source: World Bank Group, Private Sector and Infrastructure Network, *Public Policy for the Private Sector*, Note Number 246, "Private Infrastructure" (June 2002), web site http://rru.worldbank.org/viewpoint/.

electricity distribution company, as has generally been the case in South America. In general, most private investment capital has been in generation, which accounted for four-fifths of total electricity investment in the years 1990-1999 [***14***].

Investment in electricity projects in the developing world showed substantial growth through most of the 1990s, followed by a decline with the onset of the Asian economic crisis in 1997. Economic growth in developing Asia has rebounded, along with private investment in electricity projects, but investment in private-sector electricity projects in Latin America has not yet recovered, in part because of the region's weak economic performance in recent years.

Foreign capital comes from a variety of commercial and noncommercial sectors. Depending on the nation, reliance on foreign capital to finance electricity projects varies considerably. The sources of capital also vary from nation to nation, and countries frequently rely on a diversity of resources for major electricity infrastructure investment. Lenders may include multinational global institutions (such as the World Bank and the Asian Development Bank), publicly held entities, foreign government loans (such as from the U.S. Export/Import Bank), quasi-national organizations (such as Japan's Overseas Development Fund), and commercial bank loans. In addition, several developing nations have chosen to acquire listings on foreign stock exchanges [***15***].

Western Europe

In Western Europe, electricity has traditionally been supplied by state-owned national monopolies. Since the implementation of the European Electricity Directive, which became law in 1997,[26] there has been a sharp acceleration of cross-border mergers and acquisitions in Western European electricity markets [***16***]. Unlike the mergers and acquisitions in the UK electricity sector, which were largely made by U.S. utilities, those in Western Europe have typically involved other European firms, with U.S. companies playing a minor role. In 2000 and 2001 there were 35 mergers and acquisitions in Western Europe, compared with 15 in 1998 and 1999 (Figure 83).

Table 25. Private Sector Investment in Electricity Projects in Developing Regions, 1990-2000
(Million Dollars)

Country Group	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
Investment in Greenfield Electricity Projects by Region											
Sub-Saharan Africa	—	—	—	—	76	3	395	209	115	325	—
EAP	—	250	2,063	4,622	5,501	5,640	9,920	12,064	5,031	668	2,321
ECA	68	—	650	—	—	1,760	1,392	194	231	221	—
LAC	206	—	245	327	1,279	2,737	1,908	2,829	2,784	2,484	7,292
MENA	—	—	—	—	205	—	—	60	—	898	826
South Asia	135	614	32	1,048	2,078	2,546	3,780	1,486	1,147	2,311	3,357
Investment in Privatized Electricity Projects by Region											
Sub-Saharan Africa	—	—	—	—	—	—	580	274	601	150	30
EAP	44	129	1,315	171	1,499	1,151	1,313	1,246	120	1,593	1,923
ECA	—	—	246	—	1,210	1,388	1,980	1,903	276	465	821
LAC	759	19	1,907	2,640	1,316	2,748	6,840	18,314	10,958	4,285	6,029
MENA	—	—	—	—	—	—	—	—	—	—	—
South Asia	—	—	—	3	—	—	1,047	—	144	49	47
Total											
Sub-Saharan Africa	—	—	—	—	76	3	975	483	716	475	30
EAP	44	379	3,378	4,793	7,000	6,791	11,234	13,310	5,151	2,261	4,244
ECA	68	—	896	—	1,210	3,148	3,373	2,096	507	687	821
LAC	964	19	2,152	2,967	2,594	5,486	8,748	21,143	13,743	7,134	13,321
MENA	—	—	—	—	205	—	—	60	—	898	826
South Asia	135	614	32	1,051	2,078	2,546	4,827	1,486	1,291	2,359	3,404

EAP = East Asia and Pacific, ECA = Europe and Central Asia, LAC = Latin America & the Caribbean, MENA = Middle East and North Africa. For definitions of country groups, see World Bank, "Country Classification," web site www.worldbank.org/data/countryclass/classgroups.htm.

Source: Public Policy for the Private Sector, World Bank Data Base, web site www.worldbank.org.

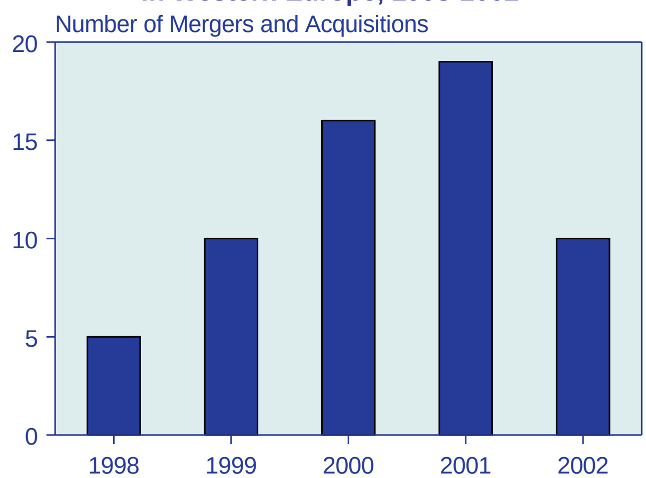
[26]The European Electricity Directive became effective in February 1997. It called for the 15 EU member nations to open at least 26 percent of their national markets to competition by February 1999, expanding to 30 percent in 2000 and 35 percent by 2003. The Directive established uniform rules for all aspects of electricity supply and called for the unbundling of generation, transmission, and distribution.

Among European nations, Germany has seen the most activity, much of which has involved German companies purchasing other German companies. Between 1998 and 2002 there were 23 mergers in the German electricity sector [*17*]. The largest of all European mergers involved E.ON, Germany's second largest electric power producer, and Ruhrgas, Germany's largest natural gas producer [*18*]. Western Europe's electricity sector is increasingly being dominated by a handful of multinationals, and growth in electricity trade has paralleled the continent's electricity industry consolidation. Between 1999 and 2000, electricity trade in Western Europe grew by 13 percent, compared with an average annual increase of 4 percent for the 1990-2000 period [*19*].

E.ON has clearly joined the ranks of multinational utilities, with subsidiaries in the Czech Republic, Denmark, Hungary, Italy, Lithuania, the Netherlands, Norway, Poland, Sweden, the United Kingdom, and the United States. In purchasing the United Kingdom's PowerGen, E.ON became the second largest provider of electricity to the UK market and owner of Kentucky-based utility LG&E. Some other European electric utilities have also extended their activities across the globe. Electricité de France, for instance, reported in its 2001 annual report a customer base of 43 million in 22 countries [*20*]. The United Kingdom's International Power, in addition to its domestic operations, had in mid-2002 operations in the United States, the Czech Republic, Portugal, Spain, Turkey, Australia, China, Malaysia, Oman, Pakistan, Thailand, and the United Arab Emirates [*21*].

Only a handful of the 15 EU members have been targets of foreign electricity investment, depending on their openness to market liberalization and other reform. Table 26 shows a number of indicators estimating the relative openness of selected EU countries' electricity sectors, as reported in an analysis sponsored by the UK Department of Trade and Industry and the government of the Netherlands. The table addresses several concepts of "openness." First is openness in the "competitive" arena, which was evaluated by two measures: (1) upstream market and wholesale competition, involving electricity generation, and (2) downstream market competition, involving the ability of customers to switch suppliers and the number of new entries into the supply market. In both the upstream and downstream measures of openness in the "competitive" segment of the industry, Norway, the United Kingdom, the Netherlands, and Germany rank much higher than France, Italy, and Spain. Second is openness in "noncompetitive areas," involving such factors as the degree of fair and open access to the transmission grid and regulatory independence. In these areas, the United Kingdom, Norway, and the Netherlands rank relatively high, but Italy ranks higher than Germany. As a result of their relative openness, levels of concentration in the electricity markets of the United Kingdom, the Netherlands, Germany,

Figure 83. Cross-Border Mergers and Acquisitions in Western Europe, 1998-2002



Source: Centre d'Économie Industrielle Ecole Nationale Superérieure des Mines de Paris, "Mergers and Acquisitions in the European Electricity Sector, Cases and Patterns" (August 2002), p. 115.

Table 26. Liberalization Indicators for Selected European Electricity Markets
(Index)[a]

Market Area	France	Germany	Italy	Netherlands	Norway	Spain	United Kingdom
Competition-Related Areas							
Upstream and Wholesale Market Competition	1.7	6.7	3.9	8.3	8.9	4.8	9.0
Downstream and Competition and Customer Benefits	1.8	5.4	3.0	4.1	8.2	3.8	7.6
Overall Competition Indicator	1.7	6.0	3.4	6.2	8.5	4.3	8.3
Noncompetitive Areas							
Network Access and Ownership	4.8	5.8	7.8	7.8	10.0	6.8	9.0
Regulatory Influence	1.7	1.7	6.7	6.7	8.3	1.7	6.7
Overall Noncompetition Indicator	4.0	4.7	7.5	7.5	9.6	5.5	8.4

[a]Index of liberalization, where 1 is the lowest value and 10 is the highest value.

Source: Oxford Economic Research Associates, *Energy Liberalisation Indicators in Europe* (London, UK: Department of Trade and Industry, October 2000), Table 2.5, p. 36, web site www.dti.gov.uk/energy/gas_and_electricity/international_policy/oxera_report.pdf.

and Norway have lessened considerably in recent years in comparison with those in other European countries (Table 27).

World Electricity Deregulation

Since the early 1980s, several nations have experimented with various models of electricity reform.[27] Some have worked reasonably well, others have not, and nations considering reform have closely watched other nations' experiments. Over the past several years, some of the developments that prevailed in global electricity markets in the 1990s appear to have stalled or, in some cases, moved backward. In India, electricity sector reforms have been introduced but then have had to be adjusted when they have failed to produce the intended results (see box on page 146). It still seems likely, however, that nations, states, and regions will continue with electricity sector reforms. Indeed, both South Korea and Mexico are moving ahead aggressively (see box on page 150); and U.S. States like Pennsylvania and Texas have launched relatively successful restructuring programs (see box on page 151). Disappointing results in some markets are expected to be brought into better perspective in the future as more reform efforts prove successful and past mistakes are avoided.

Three notable examples of reforms that have failed to live up to expectations are the restructuring programs in California, England and Wales (the UK model),[28] and Ontario. Although the California and UK experiences involved a host of different reforms, from dealing with stranded costs to implementing retail competition, where both efforts failed notably was in the implementation of competitive electricity trading arrangements—particularly in California. In Ontario, reforms did not fail to meet expectations so much as they were rejected by the public due to summer heat-related price shocks that came about when some prices were decontrolled.

To the extent that regulatory reform in electricity has been successful, it has often been emulated elsewhere. To the extent that nations have viewed their reform efforts as failed, in some cases modifications have come about; in others, reregulation has been introduced. Although various degrees of reregulation have been introduced elsewhere, including in New Zealand and several Eastern European countries [***22***], probably nowhere has the retreat from electricity reform been so dramatic as in California.

California

In designing its electricity reform model, California borrowed several elements from the UK model, including a requirement that all sales be made through a daily pool. In the California Power Exchange (PX), the pool price was determined in the following manner: the PX created an electricity supply and demand curve by combining

Table 27. Concentration in European Electricity Markets, 1999-2000

Country	Company and Market Share								
France	EDF	Other							
	80%	20%							
Germany	RWE Ag	PE	Other						
	21%	15%	64%						
Italy	ENEL SpA	Other							
	80%	20%							
The Netherlands	EPON	EPZ	UNA	EZH	Other				
	30%	21%	17%	13%	19%				
Norway	Statkraft	Norsk Hydro	Oslo Energy	Other					
	31%	12%	6%	51%					
United Kingdom	National Power	PowerGen	British Energy	Eastern Group	East Midlands Electricity	AES	Magnox Electric	Imports	Other
	19%	16%	11%	11%	9%	6%	5%	5%	18%

Source: L. Birnbaum, C. Grobbel, P. Ninios, T. Röthel, and A. Volpin, "A Shopper's Guide to Electricity Assets in Europe," *The McKinsey Quarterly*, 2000 Number 2: Europe, pp. 60-67, web site www.hgreene.com/other/mckweb/energy/shgu00.asp.

[27]Chile is generally regarded as the nation that led the current wave of wholesale electricity reform (which started in Chile during the early 1980s).

[28]Electricity reforms on England and Wales are widely referred to as UK reforms. Although the United Kingdom includes Northern Ireland and Scotland, which have embarked on separate reform efforts, what has become known as the "UK model" refers to developments in England and Wales. The UK model involved separating the four sectors of electricity supply (generation, transmission, distribution, and marketing) by ownership and by function and the implementation of a competitive electricity trading arrangement for the competitive elements of the electricity market. It also involved retail competition. For transmission and distribution, a performance-based price formula was employed, indexed to the general rate of inflation and a productivity factor. This regulatory scheme became known as RPI-X.

Electricity Reform in India

Electricity reform activities in India have increased markedly in the past decade. Reforms have been spurred by the underlying need for access to affordable, reliable electricity. India's Planning Commission estimated in the Ninth Five Year Plan (1997-2002) that additional generation capacity 40,245 megawatts would be needed to meet the government's goal of 8-percent growth in gross domestic product (GDP); however, only 19,015 megawatts of additional capacity was added.[a] The shortfall in capacity growth can be attributed to economic and technical inefficiencies in the power sector structure. A financially strong sector is needed to increase generation capacity, renovate and modernize current plants, and increase coverage and access of power service.

The poor financial health of the power sector can be attributed mainly to electricity tariffs that do not accurately reflect the cost of providing electricity service. Average revenues from the power sector are lower than the average cost of producing power. Although tariffs for the commercial and industrial sectors are set higher then their fully allocated costs, they are not high enough to offset the subsidy inherent in residential and agricultural rates. Tariffs have been influenced by political considerations. For example, many of the agricultural subsidies stemmed from the Green Revolution of the 1980s, when certain political parties used populist measures to win elections, such as offering lower tariff rates to support farmers.[b]

Another factor affecting the financial solvency of the sector is transmission and distribution (T&D) losses. T&D losses are estimated at 30 to 50 percent, which are considerably higher than those of other developing nations, such as China (7 percent) and Indonesia (12 percent).[c] T&D losses consist of both technical losses (15 to 20 percent), such as transmission line loss, and nontechnical losses (20 to 25 percent), such as theft. In addition, low billing and collection efficiency has contributed to the mounting financial insolvency of the state electricity utilities. These losses translate into commercial losses of almost $3 billion[d] or financial losses equal to nearly 1 percent of the national GDP. This is a major drain on the Indian economy, amounting to twice what the government spends on health and one-half of what it spends on education.[e]

According to the Indian constitution, the power sector is treated as a multijurisdictional entity, where both the central and state governments have jurisdiction. This has resulted in a division of activities such as policymaking, planning, financing, and operating between the state and central governments. The Ministry of Power oversees power policy at the federal level and receives guidance from the Planning Commission. The Central Electricity Authority (CEA) provides technical analysis and approval of power projects. Several public sector corporations operate generation, transmission, and rural electrification and handle financial issues surrounding those activities.

After gaining independence from the British in 1947, the government of India enacted the Electricity Supply Act of 1948. The 1948 Act brought all new power generation, transmission, and distribution under the responsibility of the public sector, especially at the state level. As a result, each state and union territory established State Electricity Boards (SEBs), vertically integrated entities that were funded by the state governments. By the early 1990s, the SEBs controlled 70 percent[f] of the generation, most of the transmission lines, and a majority of the distribution.

After sustaining a closed economy since independence, India experienced a balance of payments crisis in the early 1990s. As part of an effort to liberalize the economy, an amendment was made to the 1948 Electricity Supply Act, called the Electricity Laws (Amendment) Act of 1991. One purpose of the legislation was to encourage private investment in power generation through eight "fast track" projects. Independent power producers were invited to build power plants with incentives from the central government, including speedier technical, economic, and environmental clearances by the CEA, as well as counter-guarantees[g] by

(continued on page 147)

[a]Planning Commission, Government of India, *Tenth Five Year Plan (2002-2007)*, Vol. 2, Chapter 8, "8.2. Power," p. 897, web site http://planningcommission.nic.in/plans/planrel/fiveyr/10th/volume2/v2_ch8_2.pdf (Draft, 2003).

[b]N.K. Dubash and S.C. Rajan, "The Politics of Power Sector Reform in India" (World Resources Institute, April 2, 2001), web site http://pdf.wri.org/india.pdf.

[c]World Bank and Public-Private Infrastructure Advisory Facility, *India: Country Framework Report for Private Participation in Infrastructure* (Washington, DC, March 2000), web site http://lnweb18.worldbank.org/sar/sa.nsf/Attachments/infras/$File/Report.pdf.

[d]World Bank and Public-Private Infrastructure Advisory Facility, *India: Country Framework Report for Private Participation in Infrastructure* (Washington, DC, March 2000).

[e]E.R. Lim, Address to the World Bank Conference on Distribution Reforms (October 12-13, 2001), web site http://lnweb18.worldbank.org/SAR/sa.nsf/Attachments/engy/$File/Limpower.pdf.

[f]N.K. Dubash and S.C. Rajan, "The Politics of Power Sector Reform in India" (World Resources Institute, April 2, 2001).

[g]Counter-guarantees are guarantees by the Central government to cover the dues owed to the IPPs if the state government is not able to cover them.

Electricity Reform in India (Continued)

the government of India, a guaranteed 16-percent return on equity, and tax holidays.

The Mega-Power Policy was later introduced, with special incentives for construction and operation of thermal plants over 1,000 megawatts and hydro plants over 500 megawatts. By the end of 1993, more than 140 applications had been received for 70,000 megawatts of capacity, but by 1995-96, despite enthusiastic response to the private power policy, no projects had been initiated on the ground. Of the eight fast-track projects to which the best possible terms had been offered, none was near financial closure.[h] The most controversial and highly-publicized of the fast track projects, U.S. Enron's Dabhol power project, exemplified the many issues that were hindering growth of power generation: financial insolvency of the SEBs, political interference, lack of transparent regulatory structure, and other inefficiencies in the system.

Because of the failure of the fast track projects and the slow progress of state-level reforms, the central government acknowledged the need for more comprehensive reforms at the national level. In 1998, the central government passed the Electricity Regulatory Commission Ordinance (ERC) establishing the Central Electricity Regulatory Commission (CERC) and encouraging the establishment of State Electricity Regulatory Commissions (SERCs). CERC would be responsible for regulating tariffs of centrally owned utilities, regulating interstate transmission, providing guidelines for tariff setting to SERCs, and handling disputes between generation and transmission entities. The SERCs would be able to set tariffs, procure and purchase power, and promote competition and more efficient operations.

In 2000, the Electricity Bill was introduced to the Indian parliament as a piece of comprehensive legislation to replace all other electricity legislation. The bill has seen several incarnations while awaiting passage. The Electricity Bill consists of the such measures as generation free from licensing (except for hydro units), mandatory establishment of state-level regulatory commissions, open access for transmission and distribution, and retail tariff setting by the regulatory commissions. The Ministry of Power developed a "Blueprint for Power Sector Development" in the spring of 2001, in which power sector reform was outlined.

As discussed in the Blueprint, distribution reform is a crucial component of the reform process, which has been addressed in recent reform legislation and activity. The central government is financially supporting distribution reform through the Accelerated Power Development Reforms Programme (APDRP). Thirty-five billion rupees ($700 million) was appropriated in the 2002-2003 Union Budget for the APDRP to support 63 distribution circles. Distribution circles are an attempt to disaggregate state monitoring operations to small, manageable "profit centers," which would be responsible and accountable for their losses. The distribution circles will implement full metering, energy audits, management information systems, control of theft, increased transformation capacity, increases in the ratio of high-voltage to low-voltage transmission (it is more difficult to steal electricity from a high-voltage line), and reduction of technical losses.

Reforms at the state and union territory level began long before the central government provided an umbrella framework for power sector reform. Several states—Haryana, Orissa, and Andhra Pradesh—were encouraged by the World Bank to undertake structural reforms in their power sectors to maintain funding for power projects through Adaptable Program Loans.[i] Most states have established electricity regulatory commissions in an effort to move toward cost-based prices. Some states and union territories have unbundled their SEBs into separate units for generation, transmission, and distribution.

The process of corporatization and privatization has been much slower than other reform activities, as seen in the state of Orissa electricity reform experiment. Orissa has been at the forefront of India's state-initiated reform efforts with the World Bank playing a role in promoting, financing, and guiding the reforms. The World Bank canceled financial assistance of $156 million to Orissa for the Upper Indravati Hydroelectric Project in 1991 because of slow progress and lack of satisfaction with contracts awarded[j] and announced that it would reissue the assistance only if Orissa would reform its electricity sector.[k] In 1993, the World Bank converted some of the funds from the canceled hydro project to provide assistance to the state government's electricity reform program.

(continued on page 148)

[h]Tata Energy Research Institute, *Electrifying Reforms in the State Electricity Boards* (April 2000), web site www.teriin.org/energy/seb.htm.

[i]The World Bank Group, "Adaptable Loans: World Bank Meets Changing Demands," web site http://web.worldbank.org (Feature Story, November 20, 1997).

[j]T.A. Rajan, "Power Sector Reform in Orissa: An Ex-post Analysis of the Causal Factors, *Energy Policy*, Vol. 28 (2000), pp. 657-669.

[k]T.A. Rajan, "Power Sector Reform in Orissa: An Ex-post Analysis of the Causal Factors, *Energy Policy*, Vol. 28 (2000), pp. 657-669.

Electricity Reform in India (Continued)

In 1995, the Orissa Electricity Reform Act was enacted to support several actions. The first was the establishment of an Electricity Regulatory Commission, which was entrusted with tariff setting as well as acting as an independent regulatory body. The Orissa State Electricity Board was unbundled into state-owned companies: GRIDCO to handle transmission and distribution, Orissa Power Generation Corporation, and Orissa Hydro Power Corporation. It also allowed for private investment in generation. In 1997, privatization of the distribution sector commenced through the establishment of distribution companies. The state was divided into four geographic distribution zones, which were bid out to various private entities. Bombay Suburban Electric Supply (BSES) bought three of the zones and the U.S. firm AES bought the fourth.

Each of these actions was implemented in Orissa with mixed levels of success. One of the conditions set by the World Bank was to reduce the levels of T&D loss. However, due to a lack of accurate information on T&D losses, the distribution companies were given underestimated T&D loss values. Their loss reduction targets were based on the initial estimates, but once metering and other technologies were installed, the real loss values were ascertained to be much higher (see table).

State-Level Transmission and Distribution Losses

State	Reported T&D Losses (Percent)	
	Pre-reform Reporting	Post-reform Reporting
Orissa	23	51
Andhra Pradesh	25	45
Haryana	32	47
Rajasthan	26	43

Source: Ministry of Power, Government of India, *Blueprint for Power Sector Development* (2001).

Furthermore, several financial matters proved troubling. Because the SEB was already in poor financial shape, it was difficult to attract potential buyers in the bidding process and spur competition. Competition was also curbed by the reintroduction of horizontal and vertical integration. BSES, an electricity supplier, controlled three of the four distribution zones and AES, operating the fourth, was also heavily involved with generation in Orissa. As a result, private investors found it difficult to estimate the risks involved in participating in the newly reformed electricity sector. One of the risks was estimating revenues from the retail tariff, because the pricing system was based on an annual tariff hearing. The process of divestiture of assets to the private sector was also contentious: undervaluing the assets was perceived to be "giving them away" to the private firm; overvaluing the assets would increase the pricing of tariffs and thus increase retail prices.[l]

Delhi, a union territory, has also recently embarked on power sector reform. There is confidence in the Delhi model, which builds on the experience in Orissa and must only contend with an urban setting versus the much more dispersed rural setting. After the ERC Act in 1998, Delhi instituted the Delhi Electricity Regulatory Commission (DERC). The Delhi Vidyut Board (former electricity board) was unbundled and privatized in 1999. Based on lessons learned in Orissa, the privatization of the Delhi electricity board dealt with the issue of asset valuation, developed a new method for estimating financial risk from T&D loss, and also changed the system of bidding for distribution companies.[m]

The regulatory commission in Delhi is using a business valuation of the assets (based on the future earning potential) to avoid overvaluation. DERC has also been responsible for estimating the level of aggregate technical and commercial losses (AT&C)[n] and then setting the loss level for the bidding process.[o] Selection of bidders for the three distribution companies is based on the maximum reduction of AT&C loss over a 5-year period. (In contrast, in Orissa, the highest bidder for a 51-percent equity stake in the company was awarded the contract.)[p] Furthermore, in Delhi the distribution companies will be able to realize a 16-percent rate of return on equity only if the minimum loss reductions are met.[q] Subsidies will not be removed immediately as they were in Orissa. Instead, the territorial government has acknowledged the need for transition period measures.

(continued on page 149)

[l]L.C. Gupta and C.P. Gupta, *Financing Infrastructure Development: A Holistic Approach with Special Reference to the Power Sector* (Delhi: Society for Capital Market Research and Development, November 2001).

[m]"Power Sector Reforms and Privatization of Distribution in Delhi." Presentation by the Delhi Electricity Regulatory Commission for the Power Mission Conference (October 2002).

[n]AT&C loss includes T&D losses and collection efficiency and is defined as 1- [(billing in units / input in units) x (collection in Rupees / billing in Rupees)]. Source: 3iNetwork, *India Infrastructure Report 2003: Governance Issues for Commercialization* (Delhi: Oxford University Press, 2003), web site www.3inetwork.org / reports / IIR2003 / iir_report_content.html.

[o]Delhi Electricity Regulatory Commission, "Commission's Orders," web site www.dercind.org.

[p]3iNetwork, *India Infrastructure Report 2003: Governance Issues for Commercialization* (Delhi: Oxford University Press, 2003), web site www.3inetwork.org / reports / IIR2003 / iir_report_content.html.

[q]K. Ramanathan and S. Hasan, *Privatization of Electricity Distribution: The Orissa Experience* (New Delhi: Tata Energy Research Institute, 2003).

Electricity Reform in India (Continued)

As India's experiment in power sector reform unfolds, it remains to be seen whether Delhi will be able to internalize the issues highlighted in the Orissa privatization process. If Delhi can construct a profitable model, other states (all in different stages of the reform process) may also adopt similar methodologies and work toward a more financially viable power sector. Financial solvency of the state electricity entities may create a better investment climate for the power sector in both generation and distribution. A financially sound power sector could aid in the infrastructure development needed to support economic growth in India and other much needed services for the public.

all generator supply bids with all consumer demand bids. The clearing price (the price paid to generators by suppliers) was determined by the intersection of the supply and demand curves. This was similar to the pricing scheme initially employed in the United Kingdom, except that in the United Kingdom demand was estimated by the National Grid Company. What distinguished the California Pool was the separation of the California Independent System Operator (CAISO) from the PX. Moreover, California reforms did not provide pool participants with the hedging opportunities that the "contracts for differences" market provided in the United Kingdom. UK electricity suppliers made extensive use of such contracts, which greatly reduced their exposure to price fluctuations. The contracts for differences market allowed UK generators to hedge between 80 and 90 percent of their exposure in the day-ahead market [*23*].

Several structural flaws have been identified in California's restructured market following the State's electricity crisis. One was the requirement that California utilities purchase all their power through the PX; another was the prevention of purchasing power in a forward market that forced California utilities to buy short for their long–term electricity supply contracts; another was the degree to which the California market encouraged competition. Energy companies and energy traders have admitted to trying to manipulate the California energy market during the electricity crisis, and others have been accused of doing so by the Federal Government [*24*]. One method of manipulation involved the fee that companies could earn by reducing load on voltage lines that were overburdened. Companies have been accused of wrongfully creating congestion on paper where no congestion actually occurred. In order to do this, companies simply needed to schedule electricity to be sent over lines where the nominated values would cause congestion, even though they had no intention of actually using the lines. This act alone could result in the company being compensated for providing no service at all.

In May 2002, the U.S. Federal Energy Regulatory Commission (FERC) released Enron internal corporate memos that suggested that Enron was scheming the California energy market by creating phantom congestion and then being compensated for alleviating that congestion, and by moving electricity in and out of the State to avoid price caps. In July 2002, the FERC claimed further that Enron overcharged customers in California for natural gas. And in August 2002, the FERC commenced an investigation to see whether three companies sought to control supply in the California market and thus create a runup in prices and profits. In November 2002, Williams Companies agreed to pay $400 million to settle accusations that it had gamed the West Coast electricity market and to restructure a $4.3 billion long-term electricity contract with California, whereby the State plans to save $1 billion [*25*].

In July 2002, several companies had reached a settlement with the State government to reimburse the State for a portion of the profits they earned during the energy crisis. The California State government was seeking $21 billion of the $43 billion in long-term contracts the State signed in 2001, claiming that the contracts were signed when the companies exercised illegal control over the California electricity market [*26*]. In March 2003, FERC staff recommended that the Commission issue "show cause" orders to companies that alledgedly violated California's trading rules. Under the show cause orders, companies would be held liable for the repayment of unfair profits unless they prove that their actions were justified [*27*].

The UK Model

In contrast to California's experience with electricity reform, the UK experience was largely successful, with the exception of introducing a satisfactory level of competition in the national pool. In early 2001, the United Kingdom shut down the pool, which had been in operation since 1990, and embarked on a new form of electricity trading system, called the New Electricity Trading Arrangement (NETA). This was done because it was felt that the old pool arrangements did not foster adequate competition. The initial pool setup was supposed to be the major arena in which competition was to be introduced in the UK electricity market [*28*]. However, even after the UK generation market was broken up during the mid-1990s, the UK pool was still highly concentrated.

The effort to instill more competition in the UK electricity pool involved policy changes that amounted to "fine tuning." The power pool was altered so that the clearing price became the bid price rather than the system marginal price as in the past. Further, generators were no longer forced to bid into the pool and were free to negotiate bilateral contracts.

The most commonly perceived failure of the old UK electricity pool was that bidding prices within the pool could easily be manipulated due to the small number of participants and to pool rules that were susceptible to manipulation through strategic bidding. Both auction theory and game theory come into play in trying to create a pool immune to such collusive behavior. In any event, since the initiation of the UK electricity pool in 1990, most of the efficiency gains realized through cost reductions at generation companies were not passed through to consumers. Despite generation costs falling by half, pool prices changed little after the inception of the electricity pool [***29***].

One feature of the UK pool that may have led to strategic bidding was the system marginal price. The way in which the UK electricity auction occurred was that generators bid into the system up to the point at which the bids provided enough capacity to clear demand as forecasted by the National Grid Company. The price bid on the last unit of capacity to clear the system became the system marginal price. This provided an incentive to manipulate the system by bidding in higher cost units in order to drive up the price, which is exactly what the major operators in the UK pool have frequently been accused of doing.

The major difference between NETA and the original pool is that the system marginal price, which was provided to all bidders who cleared the pool under the old system, was replaced by a pay-as-bid price. This was done so as to make market manipulation through strategic bidding less likely. Another significant difference is that NETA allows bilateral forward contracts. About 98 percent of electricity is now traded bilaterally [***30***]. NETA also allowed derivative trading, which provided another means of hedging exposure to price fluctuations.

NETA differs in several other important instances from the old UK electricity pool. NETA allows for self-dispatch instead of the National Grid Company performing the role of scheduler and orderer in addition to its role as a transmission provider, which made it the equivalent of the PX and CAISO combined. Under the old system, the responsibility of ensuring adequate electricity supply was entirely in the hands of the National Grid Company, which was responsible for forecasting electricity demand on a half-hourly basis for the following day. Under NETA, this responsibility was transferred to the generators themselves. Further, NETA opened up the wholesale market to non-generators, thus allowing commodity traders to participate in the market [***31***]. Unlike the old pool, NETA does not include a capacity mechanism.

Since NETA was implemented, electricity prices have fallen dramatically in the United Kingdom. However, a

South Korea and Mexico Press Ahead with Reforms

South Korea is one nation still moving ahead aggressively with electricity reform. A central element of the reforms is a dismantling of the state-owned utility, Kepco, along its functional units: generation, transmission, and distribution. The first phase of restructuring was scheduled for 2000, when Kepco was split into six individual companies: one nuclear and hydro company and five thermal power companies. The second phase of restructuring, which took place in 2000-2002, involved the creation of a market, a system operator, and an electricity pool. During the third phase, 2003-2009, regional distribution companies are scheduled for privatization.[a]

Mexico has also proceeded with electricity reform efforts. Mexican electricity reforms got started in 1992 with the passage of the Public Electricity Service Act, which allowed a limited opening of the electricity supply industry to non-government-owned entities. Private parties were allowed to participate in electricity generation, although they had to sell their power to the federal electricity commission. As a result of the Act, an independent electricity sector has emerged in Mexico, along with some foreign investment. The Mexican government has estimated that the nation will need $5 billion in electricity investment over the next 10 years. The president of Mexico hopes that private investors will add 30,000 megawatts of capacity over the next 10 years, which would nearly double Mexico's current capacity. The Act retained the monopoly of the Comisión Federal de Electricidad (CFE) as sole purchaser of electric power. After more than 2 years of debate, the Mexican Senate in November 2002 forwarded a legislation bill that would alter the Mexican constitution to allow private investment in electricity. The bill would also create separate generation, transmission, and distribution companies, create an independent system operator, and allow for the development of a merchant power industry.[b]

[a]M. Hutchinson and C.K. Liu, "South Korea's Managed Market Solution," *CERA's Asia Gas & Power Advisory Service* (April 11, 2003), web site www.cera.com.
[b]E. Malkin, "Mexico's Fox Proposes Opening Power Sectors," *The New York Times* (August 12, 2002), p. C4.

Successful Electricity Restructuring in Texas and Pennsylvania

Over the past decade, U.S. States have been exploring options for opening electricity markets to competition. Although California's restructuring failures are well documented, a number of States have had more successful electricity restructuring programs, and efforts to restructure electricity markets are continuing. Twenty-four States and the District of Columbia have enacted legislation that allows various levels of retail competition, and 18 States and the District of Columbia are actively implementing restructured retail markets. All are currently considered to be in the "transition" to competition. Pennsylvania and Texas provide two examples of what are generally regarded as successful restructuring programs, although both systems continue to be fine-tuned as issues arise.

"Successful competition" has been measured by such factors as the amount of load supplied by competitive suppliers, the level of sustained price decreases, and the ability to weather price spikes and / or support conditions that discourage frequent price spikes. Within the wholesale market, the ability to manage congestion, provide for competitive prices, and limit the ability of participants to exercise market control are considered important to maintaining a successful open market structure.

Pennsylvania's wholesale electricity market is controlled by the PJM Regional Transmission Organization (RTO), which operates in Pennsylvania, New Jersey, Maryland, Delaware, Washington, DC, and parts of Virginia and is widely recognized as the most successful U.S. RTO to date. PJM provides settlement of day-ahead and hourly prices, as well as energy scheduling and balancing for the Pennsylvania, New Jersey, Delaware and Maryland region, and agreements are in the works to coordinate and perhaps merge with other RTOs and power areas. PJM's system of locational marginal pricing is emerging as an effective way to manage congestion of the transmission grid through competitive prices.

Pennsylvania's reform efforts implemented several unique policy measures. For instance, the State initiated a shopping credit—a credit on the generation portion of a customer's bill to be used to pay a competitive provider. The customer would keep savings realized by choosing the competitive provider. This, coupled with a very humorous consumer education program, was credited for several years of success in inducing customer switching (almost one-quarter of the total State load at one point).

Pennsylvania has also led the development of a Mid-Atlantic model for uniform business practices.[a] Dramatic increases in natural gas prices in 2002, which led to substantial increases in U.S. electricity prices, diminished the competitiveness of some electricity suppliers. Many left the market, initiating a customer return to "providers of last resort"—suppliers designated for customers dropped by their competitive suppliers. After 2001, however, this service was provided not by incumbent utilities but by the suppliers that offered the best rates. For example, most customers of southwestern Pennsylvania's Duquesne Light finished paying stranded costs in March 2002, and now 27 percent of the electricity load in the territory is supplied competitively.[b] Even with the increase in natural gas prices, Pennsylvania's electricity prices have been reduced by about 8 percent (in real dollars) since restructuring legislation was enacted in 1996.

In Texas, full retail competition began on January 1, 2002, for customers in the Electric Reliability Council of Texas (ERCOT) RTO. Today, about 25 percent of demand in the ERCOT area is served by competitive suppliers.[c] In September 2001, utilities in Texas began the process of auctioning off part of their generating capacity. Restructuring legislation requires each generation company affiliated with a former monopoly utility to sell entitlements to at least 15 percent of its installed generation capacity at least 60 days before full retail competition begins.[d] Customers that require over 1.0 megawatts of generating capacity are not provided default service. In other words, they must choose a competitive service. Default and provider-of-last-resort services are provided at market rates.

The market in Texas differs from restructured markets in other States in that utilities are required to establish separate affiliates to provide retail service to customers, forcing distribution companies to stay out of retail marketing and generation. This has achieved a level of functional separation similar to the forced divestiture required by States such as Massachusetts. The Texas Public Utility Commission is working with ERCOT to explore transmission congestion and pricing reform, as well as demand response programs.

[a]Center for the Advancement of Energy Markets, *Electricity Retail Energy Deregulation Index 2001: For the United States, Canada, New Zealand, and Portions of Australia and the United Kingdom* (Washington, DC, April 2003), web site www.caem.org.

[b]Center for the Advancement of Energy Markets, *Electricity Retail Energy Deregulation Index 2001: For the United States, Canada, New Zealand, and Portions of Australia and the United Kingdom* (Washington, DC, April 2003), web site www.caem.org.

[c]Public Utility Commission of Texas, *Report to the 78th Texas Legislature: Scope of Competition in Electric Markets in Texas* (January 2003).

[d]Energy Information Administration, "Status of State Electric Industry Restructuring Activity as of February 2003," web site www.eia.doe.gov / cneaf / electricity / chg_str / texas.html (February 2003).

concern arising from NETA's initial success is that by driving electricity prices substantially lower, NETA will not remunerate electricity companies for investing in future power stations, thus guaranteeing future supply shortages and higher prices. The industry has called for a capacity mechanism to be put in place to ensure against future electricity shortages. Since March 2002, several generation companies have shut down capacity as a result of the low pool prices and have voiced concerns that NETA was at fault [32].

Devising trading arrangements suitable to a commodity with such unusual features as electricity has been an area that has dogged reformers in several countries, states, and provinces. Sharp price spikes are not new to pool-based electricity exchange systems. One concern that arose over California's recent experience with its electricity pool is whether suppliers under certain pool designs can achieve excessive market power. In countries that have adopted pool-based electricity trading systems, such as Canada, the United Kingdom, and Australia, similar concerns have arisen over the connection between price spikes and market power.

Ontario

Canada is another country that has backtracked somewhat in its electricity reform efforts. Since the early 1990s, some Canadian provinces have undertaken efforts at electricity reform. Most have involved modest changes, such as providing large users with the freedom to choose their electricity suppliers. Thus far, only Alberta and Ontario have embarked on wide-scale reforms.

Alberta was first in implementing electricity reform, a central feature of which was the initiation of an electricity pool. More recently, Ontario has introduced electricity reform efforts that include the creation of an electricity pool, dismantling of the former state-owned utility, future privatization, and consumer choice. One motivation behind Ontario's electricity reform was the unsatisfactory performance of the nuclear power plants operated by the previous public utility, Ontario Hydro [33].

When Ontario began restructuring its electricity industry, the province faced a number of issues, many of which had motivated electricity reform efforts elsewhere. In particular, Ontario's electricity provider at the time, Ontario Hydro [34], was viewed as inefficiently run, as having charged excessively high prices, and as having accumulated financially imprudent levels of debt. One indicator of the electricity sector's inefficiency was that Ontario Hydro's nuclear capacity factor averaged 80 percent in 1980-1983, fell to 70 percent in 1984-1989, and then fell to 65 percent in 1990-1996.

When electricity reform was being considered in Ontario, another justification was that several other nations and regions had already done it, and reforms were necessary to keep Ontario economically competitive. In several respects the reforms undertaken in Ontario resembled those in the United Kingdom, California, and elsewhere [35]. In 1997, the Ontario government developed a nine-point plan for dealing with several shortcomings in the province's electricity industry [36]. The plan was intended to:

- Create a competitive market in the year 2000 for both wholesale and retail customers
- Establish an Independent Market Operator and provide for an interim supply market for replacement power
- Separate monopoly operations from competitive businesses throughout the electricity sectors
- Provide the Ontario Energy Board with an expanded mandate to protect electricity consumers
- Take steps to ensure environmental protection
- Encourage cost savings in the local distribution sector
- Establish a level playing field on taxes and regulation
- Restructure Ontario Hydro into new companies with clear business mandates
- Take action to put the new electricity companies on a sound economic and financial footing.

The Energy Competition Act, which went into effect in 1998, did away with Ontario Hydro's monopoly in electricity supply [37]. Ontario Hydro was split into two successor companies: Ontario Power Generation, which assumed ownership of the generation assets of Ontario Hydro, and Hydro One, which assumed ownership of the transmission assets. The two companies began operating separately in April 1999. Three other entities were also created: an Independent Electricity Market Operator (IMO) similar to the CAISO in California; an Electrical Safety Authority (ESA); and an Ontario Electricity Financial Corporation (OEFC), which took on the multibillion-dollar debt of the former Ontario Hydro.

The purpose of the nonprofit IMO was to manage the pool and transmission system; the purpose of the ESA was to conduct electrical safety inspections; and the purpose of OEFC was to service and retire the former Ontario Hydro's provincially guaranteed debt and manage certain other legacy liabilities, most related to investments in nuclear power. Ontario Hydro's debt had increased from $12 billion in 1980 to $38 billion in 1999. As in the United Kingdom and California, the issue of how to address the financing of stranded costs (mostly related to nuclear power) was a major concern in Ontario's electricity reform. In Ontario, a portion of the costs are to be recovered through transition surcharges[29] [***38***, ***39***].

Rather than privatizing Ontario Power Generation outright, the Ontario government chose to introduce market principles by requiring that the new company "decontrol" generation assets. This was achieved to a small degree when Ontario Power Generation leased its Bruce nuclear power units to Bruce Power Partnership, which was 95 percent owned by British Energy. Ontario Power Generation was also ordered to shed 4,000 megawatts of assets over 3 years and to reduce its share of the province's electricity market to 35 percent by 2012. Although the provincial government had intended to privatize Hydro One as a part of the overall reform scheme, in January 2003 the provincial premier announced that it would retain full ownership of the entity [***40***]. It had intended that the proceeds from the sale of Hydro One were to be used to retire a portion of the debt (stranded costs) of the former Ontario Hydro.

In contrast to generation, Hydro One, the province's transmission operations, has continued to be regulated, although Ontario's intent was to eventually adopt a performance-based regulation, similar to the form of regulation employed in the United Kingdom. The Ontario Energy Board Act (a companion piece of legislation to the Energy Competition Act) instituted the Ontario Energy Board (OEB), which is an independent quasi-judicial entity. The OEB licenses all market participants in the electricity sector and oversees transmission and distribution rates. The board is also charged with assuring that nondiscriminatory open access is implemented in transmission.

Ontario also intended to introduce retail competition. The Competition Act envisioned full retail competition being implemented in 2000 for all classes of customers—industrial, commercial, and residential.[30] Power marketers were allowed to begin contacting potential customers in March 2000 and to enter into contracts the following November.

In May 2002, Ontario began operation of the electricity pool. The pool was similar to the California pool in that both electricity suppliers and consumers were to bid into the market, with no forward market as an alternative. The pool's pricing mechanism was set up much like the UK pool. The price offered by the last unit to clear the market (the system marginal price) became the market price that was paid to all generators.

Ontario did not, however, allow for completely competitive market-based prices. Rather, electricity consumers were allowed either to choose to purchase power at a fixed price or to choose one based on the wholesale pool price. During the summer of 2002, exceptionally hot weather sent electricity prices soaring in the pool as they attained their market-clearing levels. Although the price spikes did not come close to those experienced in the California, monthly bills showed a 20-percent increase above government forecasts [***41***]. As a result of public concern, in November 2002, Ontario's government ordered a 4.3 cents (Canadian) per kilowatthour cap on wholesale prices and rebates to consumers for previous price increases.

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